3. DISCHARGED MATERIAL

The quantity and composition of the potential discharges are a consideration under Factor 1 of the 10 factors used to determine unreasonable degradation. The potential for bioaccumulation or persistence of the pollutants in these discharges is addressed in Chapter 5, Toxicity and Bioaccumulation.

3.1 Discharges Covered Under the Permit

In this chapter, the following discharges are characterized by their sources and uses during drilling and production operations and by their physical and chemical compositions.

Exploration and development activities for the extraction of oil and gas include work necessary to locate, drill, and complete wells. Exploration activities are those operations that involve drilling wells to determine potential hydrocarbon reserves. Exploratory activities are usually of short duration at a given site, involve a small number of wells, and are generally conducted from mobile drilling units. Development activities involve drilling production wells once a hydrocarbon reserve has been discovered and delineated. These operations, in contrast to exploration activities, may involve a large number of wells which may be drilled from either fixed or floating platforms or mobile drilling units. Production operations, which consist of the work necessary to bring hydrocarbon reserves from the producing formation, begin with the completion of each well at the end of the development phase. The primary wastewater sources from the exploration, development and production phases of the offshore oil and gas extraction industry produce the following wastewater sources:

Drill Cuttings
Deck Drainage
Sanitary Waste
Domestic Waste
Completion Fluids
Cement
Workover Fluids
Blowout Preventer Control Fluids
Desalination Unit Discharge
Ballast and Storage Displacement Water
Bilge Water
Uncontaminated Seawater
Boiler Blowdown
Source Water and Sand

3.2 Drilling Fluids

Drilling fluids (also known as drilling muds or muds) are suspensions of solids and dissolved materials in a water, oil, or synthetic base that are used in rotary drilling operations. The rotary drill bit is rotated by a hollow drill stem made of pipe, through which the drilling fluid is circulated. Drilling fluids are formulated for each well to meet specific physical and chemical requirements. Geographic location, well depth, rock type, geologic formation, and other conditions affect the mud composition required. The number and nature of mud components varies by well, and several to many products may be used at any time to create the necessary properties. The primary functions of a drilling fluid include the following.

- Transport drill cuttings to the surface
- Control subsurface pressures
- Lubricate the drillstring
- Clean the bottom of the hole
- Aid in formation evaluation
- Protect formation productivity
- Aid formation stability (Moore, 1986).

The functions of drilling fluid additives and typical additives are listed on Table 3-1. Five basic components account for approximately 90 percent by weight of the materials that compose drilling muds: barite, clay, lignosulfonate, lignite, and caustic soda (EPA, 1993).

Barite. Barite is a chemically inert mineral that is heavy and soft. In water-based muds, barite is composed of over 90 percent barium sulfate. Synthetic-based fluids contain about 33% barium sulfate. Barium sulfate is virtually insoluble in seawater. Barite is used to increase the density of the drilling fluid to control formation pressure. The concentration of barite in drilling fluid can be as high as 700 lb/bbl (Perricone, 1980). Quartz, chert, silicates, other minerals, and trace levels of metals can also be present in barite. Barium sulfate contains varying concentrations of metals depending on the characteristics of the deposit from where the barite is mined. One study indicates that there is a correlation between cadmium and mercury and other trace metals in the barite (SAIC, 1991). EPA currently regulates cadmium and mercury concentrations in barite and refers to the stock barite that meets EPA limitations as “clean” barite. Table 3-2 provides mean metals concentrations in “clean” barite compared to their concentration in the earth's crust.

Clay. The most common clay used is bentonite, which is composed mainly of sodium montmorillonite clay (60 to 80%). It can also contain silica, shale, calcite, mica, and feldspar. Bentonite is used to maintain the rheologic properties of the fluid and prevent loss of fluid by providing filtration control in permeable zones. The concentration of bentonite in mud systems is usually 5 to 25 lb/bbl. In the presence of concentrated brine, or formation waters, attapulgite or sepiolite clays (10 to 30 lb/bbl) are substituted for bentonite (Perricone, 1980).

Lignosulfonate. Lignosulfonate is used to control viscosity in drilling muds by acting as a thinning agent or deflocculant for clay particles. Concentrations in drilling fluid range from 1 to 15 lb/bbl. It is made from the sulfite pulping of wood chips used to produce paper and cellulose. Ferrochrome lignosulfonate, the most commonly used form of lignosulfonate, is made by treating lignosulfonate with sulfuric acid and sodium dichromate. The sodium dichromate oxidizes the lignosulfonate and cross linking occurs. Hexavalent chromium supplied by the chromate is reduced during reaction to the trivalent state and complexes with the lignosulfonate. At high down-hole temperatures, the chrome binds onto the edges of clay particles and reduces the formation of colloids. Ferrochrome lignosulfonate retains its properties in high soluble salt concentrations and over a wide range of alkaline pH. It also is resistant to common mud contaminants and is temperature stable to approximately 177°C (EPA, 1993).

Table 3-1. Functions of Common Drilling Fluid Chemical Additives [a]

Action	Typical Additives	Function
Alkalinity and pH Control	Caustic soda; sodium bicarbonate; sodium carbonate; lime	1. Control alkalinity 2. Control bacterial growth
Bactericides	Paraformaldehyde; alkylamines; caustic soda; lime; starch	Reduce bacteria count NOTE: Halogenated phenols are not permitted for OCS use
Calcium Removers	Caustic soda; soda ash; sodium bicarbonate; polyphosphate	Control calcium buildup in equipment
Corrosion Inhibitors	Hydrated lime; amine salts	Reduce corrosion potential
Defoamers	Aluminum stearate; sodium aryl sulfonate	Reduce foaming action in brackish water and saturated salt muds
Emulsifiers	Ethyl hexanol; silicone compounds; lignosulfonates; anionic and nonionic products	Create homogenous mixture of two liquids
Filtrate Loss Reducers	Bentonite; cellulose polymers; pregelated starch	Prevent invasion of liquid phase into formation
Flocculants	Brine; hydrated lime; gypsum; sodium tetraphosphate	Cause suspended colloids to group into "flocs" and settle out
Foaming Agents		Foam in the presence of water and allow air or gas drilling through formations producing water
Lost Circulation Additives	Wood chips or fibers; mica; sawdust; leather; nut shells; cellophane; shredded rubber; fibrous mineral wool; perlite	Used to plug in the well-bore wall to stop fluid loss into formation
Lubricants	Hydrocarbons; mineral oil; diesel oil; graphite powder; soaps	Reduce friction between the drill bit and the formation
Shale Control Inhibitors	Gypsum; sodium silicate; polymers; lime; salt	Reduce well collapse caused by swelling or hydrous disintegration of shales
Surface Active Agents (Surfactants)	Emulsifiers; de-emulsifiers; flocculants	1. Reduce relationship between viscosity and solids concentration 2. Vary the gel strength 3. Reduce the fluid plastic viscosity
Thinners	Lignosulfonates; lignite; tannis; polyphosphates	Deflocculate associated clay particles
Weighting Material	Barite; calcite; ferrophosphate ores; siderite; iron oxides (hematite)	Increase drilling fluid density
Petroleum Hydrocarbons	Diesel oil; mineral oil	Used for specialized purposes such as freeing stuck pipe

[a] Source: EPA, 1993.

Table 3-2. Trace Metal Concentrations in Barite[a]

Pollutant	Estimated Concentrations on Dry Weight Basis (mg/kg)	
	Barite	Earth's Crust
Aluminum	9,069.9	
Antimony	5.7	
Arsenic	7.1	2
Barium	359,747	
Beryllium	0.7	
Cadmium	1.1	0.2
Chromium	240	
Copper	18.7	45
Iron	15,344.3	50,000
Lead	35.1	15
Mercury	0.1	0.1
Nickel	13.5	80
Selenium	1.1	
Silver	0.7	
Thallium	1.2	
Tin	14.6	
Titanium	87.5	
Zinc	200.5	65

[a] Source: EPA, 1993.

Lignite. Lignite is a soft coal used in drilling muds as a deflocculant for clay, to control the filtration rate, and to control mud gelation at elevated temperatures. Concentrations vary from 1 to 25 lb/bbl (Perricone, 1980). Lignite products are more commonly used as thinners in freshwater muds.

Caustic Soda. Sodium hydroxide is used to maintain the pH of drilling muds between 9 and 12. A pH of 9.5 provides for maximum deflocculation and keeps the lignite in solution. A more basic pH lowers the corrosion rate and provides protection against hydrogen sulfide contamination by limiting microbial growth.

Drilling fluids can be water-based, oil-based, or synthetic-based. In water-based fluids (WBF), water is the suspending medium for solids and is the continuous phase, whether or not oil is present. Water-based drilling fluids are composed of approximately 50 to 90 percent water by volume, with additives comprising the rest.

WBFs have been classified into eight generic types based on their compositions (EPA, 1993).

1. Potassium/polymer fluids are inhibitive fluids, as they do not change the formation after it is cut by the drill bit. They are used in soft formations such as shale where sloughing may occur.

2. Seawater/lignosulfonate fluids are also inhibitive. This type of mud is used to maintain viscosity by binding lignosulfonate cations onto the broken edges of clay particles. It is also used to control fluid loss and to maintain the borehole stability. Under more complicated conditions, such as higher temperatures, this type of mud can be easily altered.

3. Lime (or calcium) fluids are inhibitive fluids. The viscosity of the mud is reduced as calcium binds the clay platelets together to release water. This type of mud system can maintain more solids. Lime fluids are used in hydratable, sloughing shale formations.

4. Nondispersed fluids are used to maintain viscosity, to prevent fluid loss, and to provide improved penetration, which may be impeded by clay particles in dispersed fluids.

5. Spud fluids are noninhibitive muds that are used in approximately the first 300 meters of drilling. This is the most simple mixture of mud and contains mostly seawater and a few additives.

6. Seawater/freshwater gel fluids are inhibitive muds used in early drilling to provide fluid control, shear thinning, and lifting properties for removing cuttings from the hole. Prehydrated bentonite is used in both seawater and freshwater fluids and attapulgite is used in seawater when fluid loss is not a concern.

7. Lightly treated lignosulfonate freshwater/seawater fluids resemble seawater/ lignosulfonate muds except their salt content is less. The viscosity and gel strength of this mud are controlled by lignosulfonate or caustic soda.

8. Lignosulfonate freshwater fluids are similar to the muds at #2 and #7 except the lignosulfonate content is higher. This mud is used for higher temperature drilling.

Oil-based drilling fluids (OBF) are those with oil, typically diesel, as the continuous phase and water as the dispersed phase. These fluids were found to be toxic to marine organisms and are no longer permitted for discharge. Due to the high cost of hauling the muds to shore and proper land disposal, the use of oil-based muds, particularly in offshore areas, has decreased significantly.

Synthetic-Based Drilling Fluids

Synthetic-based drilling fluids represent a new technology which developed in response to the widespread permit discharge bans of oil-based drilling fluids. An SBF has a synthetic material as its continuous phase and water as the dispersed phase. The types of synthetic material which have been used include vegetable esters, polyalpha olefins (PAO), linear alphaolefins, internal olefins, and esters (USEPA, 1996). A model SBF formulation consists of 47% synthetic base fluid, 33% solids, and 20%

water (by weight), a 70%/30% ratio of synthetic base to water, typical of commercially available SBFs (USEPA 1999).

SBFs are reported to perform as well as or better than OBFs in terms of rate of penetration, borehole stability, and shale inhibition. Due to decreased washout (erosion), drilling of narrower gage holes, and lack of dispersion of the cuttings in the SBF, compared to WBF the quantities of muds and cuttings waste generated is reduced, reportedly in some cases by as much as 70 per cent. (Burke and Veil, 1995; Candler, et al, 1993).

The pollutants of concern from water-based muds discharges are primarily metals, most of which are associated with the barite added to the mud system and organics, which are added for lubricity or to free stuck pipe. The pollutant concentrations in water-based drilling fluid discharges characteristic of most offshore operations are presented in Table 3-3. The naphthalene concentration in Table 3-3 is based on a pill volume of 100 bbl and is calculated for an average well depth and mud volume.

According to standard formulation data, all of the solids in synthetic-based fluids are barite, making SBF a source of heavy metals and total suspended solids. SBFs are also one source of the conventional pollutant oil and grease. Table 3-4 shows the waste characteristics of SBFs.

Table 3-3. Drilling Fluids Pollutant Concentrations[a]

Pollutant	Concentration in Whole Mud (µg/l)
Aluminum	4,123,615
Antimony	2,592
Arsenic	3,228
Barium	163,558,125
Beryllium	318
Cadmium	500
Chromium	109,116
Copper	8,502
Iron	6,976,260
Lead	15,958
Mercury	45
Nickel	6,138
Selenium	500
Silver	318
Thallium	546
Tin	6,638
Titanium	39,800
Zinc	91,157
Naphthalene	330

a Source: EPA, 1993.

Table 3-4. Synthetic-based fluids drilling waste characteristics. (Modified from USEPA, 1999).

Waste Characteristics	Value
SBF formulation	47% synthetic base fluid, 33%barite, 20% water (by weight)
Synthetic base fluid density	280 pounds per barrel
Barite density	1,506 pounds per barrel
SBF drilling fluid density	9.6 pounds per gallon
Percent (vol.) formation oil	0.2%
Pollutant Concentrations in SBF	
Conventionals	**lbs/bbl of SBF**
Total oil as synthetic base fluid	190
Total oil as formation oil	0.59
Total suspended solids as barite	133
Priority Pollutant Organics	**lbs/bbl of SBF**
Naphthalene	0.0010052
Fluorene	0.0005483
Phenanthrene	0.0013004
Phenol	7.22E-08
Priority Pollutant Metals	**mg/kg/Barite**
Cadmium	1.1
Mercury	0.1
Antimony	5.7
Arsenic	7.1
Berylium	0.7
Chromium	240
Copper	18.7
Lead	35.1
Nickel	13.5
Selenium	1.1
Silver	0.7
Thallium	1.2
Zinc	200.5
Non-Conventional Metals	**mg/kg Barite**
Aluminum	9069.9
Barium	120000
Iron	15344.3
Tin	14.6
Titanium	87.5
Non-Conventional Organics	**lbs/bbl of SBF**

Alkylated benzenes	0.0056587
Alkylated naphthalenes	0.0531987
Alkylated fluorenes	0.0064038
Alkylated phenanthrenes	0.0080909
Alkylated phenols	0.0000006
Total biphennyls	0.0105160
Total dibenzothiophenes	0.0000092

The discharge of neat synthetic-based drilling fluids is prohibited under this permit, however the permit will allow discharges of water-based fluids. Because of their cost, SBFs, used or unused, are considered a valuable commodity by the industry and not a waste. It is industry practice to continuously reuse the SBF while drilling a well interval, and at the end of the well, to ship the remaining SBF back to shore for refurbishment and reuse. Compared to water-based fluids, SBFs are relatively easy to separate from the drill cuttings because the drill cuttings do not disperse in the drilling fluid to the same extent. With WBF, due to dispersion of the drill cuttings, drilling fluid components often need to be added to maintain the required drilling fluid properties. These additions are often in excess of what the drilling system can accommodate. The excess "dilution volume" of WBF is discharged. This excess dilution volume does not occur with SBF. For these reasons, SBF is only discharged as a contaminant of the drill cuttings waste stream. It is not discharged as neat drilling fluid (drilling fluid not associated with cuttings).

3.3 Drill Cuttings

Drill cuttings are fragments of the geologic formation broken loose by the drill bit and carried to the surface by the drilling fluids that circulate through the borehole. They are composed of the naturally occurring solids found in subsurface geologic formations and bits of cement used during the drilling process. Cuttings are removed from the drilling fluids by a shale shaker and other solids control equipment before the fluid is recirculated down the hole.

The volume of cuttings generated while drilling the SBF intervals of a well depends on the type of well (development or production) and the water depth. According to analyses of the model wells provided by industry representatives, wells drilled in less than 1,000 feet of water are estimated to generate 565 barrels of cuttings for a development well and 1,184 barrels of cuttings for an exploratory well. Wells drilled in water greater than 1,000 feet deep are estimated to generate 855 barrels of cuttings for a development well, and 1,901 cuttings for an exploratory well (USEPA, 2000). These values assume 7.5 percent washout, based on the rule of thumb reported by industry representatives of 5 to 10 percent washout when drilling with SBF. Washout is caving in or sluffing off of the well bore. Washout, therefore, increases hole volume and increases the amount of cuttings generated when drilling a well. Assuming no washout, the values above become, respectively, 526, 1,101, 795, and 1,768, barrels of dry cuttings.

As the drilling fluid returns from downhole laden with drill cuttings, it normally is first passed through primary shale shakers, vibrating screens, which remove the largest cuttings, ranging in size of approximately 1 to 5 millimeters. The composition of a shale-shaker discharge is presented in Table 3-4. The drilling fluid may then be passed over secondary shale shakers to remove smaller drill cuttings. Finally, a portion or all of the drilling fluid may be passed through a centrifuge or other shale shaker with a very fine mesh screen, for the purpose of removing the fines. It is important to remove fines from the drilling fluid in order to maintain the desired flow properties of the active drilling fluid system. Thus, the cuttings waste stream usually consists of larger cuttings from a primary shale shaker, smaller cuttings from a secondary shale shaker, and fines from a fine mesh shaker or centrifuge. As a final step, the wet cuttings are sent to a dryer which uses high temperatures to separate SBFs from cuttings. The dried residue from the dryer consists of fine cuttings and SBF material and is transported to an onshore waste handlig facility. The cleaned cuttings are then discharged overboard.

The recovery of SBF from the cuttings serves two purposes. The first is to deliver drilling fluid for reintroduction to the active drilling fluid system and the second is to minimize the discharge of SBF. The recovery of drilling fluid from the cuttings is a conflicting concern, because as more aggressive methods are used to recover the drilling fluid from the cuttings, the cuttings tend to break down and become fines. The fines are more difficult to separate from the drilling fluid (an adverse affect for pollution control purposes), but in addition they deteriorate the properties of the drilling fluid. Increased recovery from cuttings is more of a problem for WBF than SBF because in WBFs the cuttings disperse more and spoil the drilling fluid properties. Therefore, compared to WBF, more aggressive methods of recovering SBF from the cuttings wastestream are practical. These more aggressive methods may be justified for cuttings associated with SBF so as to reduce the incidental discharge of SBF. This, consequently, will reduce the quantity of toxic organic and metallic components of the drilling fluid discharged.

Table 3-5. Mineral Composition of a Shale-Shaker Discharge from a Mid-Atlantic Well[a]

Pollutant	Percent by Weight (Dry Basis)
Barium Sulfate	3
Montmorillonite	21
Illit	11
Kaolinite	11
Chlorite	6
Moscovite	5
Quartz	23
Feldspar	8
Calcite	5
Pyrite	2
Siderite	4

a Source: Adapted by NRC (1983) from Ayers et al. (1980b); 65% solids, density 1.7 g/cm^3.

3.4 Produced Water

Produced water (also known as production water, process water, formation water, or produced brine) is the water brought up from the hydrocarbon-bearing strata with the produced oil and gas. Produced water includes small volumes of treating chemicals that return to the surface with the produced fluids and pass through the produced water system. It constitutes a major waste stream from offshore oil and gas production activities.

Produced water is composed of formation water that is brought to the surface combined with the oil and gas, injection water (if used for secondary oil recovery and has broken through into the oil formation), and various added chemicals (biocides, coagulants, corrosion inhibitors, etc.). The constituents include dissolved, emulsified, and particulate crude oil constituents, natural and added salts, organic and inorganic chemicals, solids, and trace metals. Chemicals used on production platforms such as biocides, coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors also may be present.

Produced water constitutes the major waste stream from offshore oil and gas production activities. The pollutant concentrations in produced water used in this analysis were used for development of the final effluent guidelines for the offshore subcategory (EPA, 1993). The concentrations are based on treatment by gas flotation before discharge. The pollutants and their average concentrations are presented in Table 3-6.

Produced water can be classified into three groups--meteoric, connate, and mixed waters--depending on its origin. Meteoric water is water that originates as rain and fills porous or permeable shallow rocks or percolates through them along bedding planes, fractures, and permeable layers. Carbonates, bicarbonates, and sulfates in the produced water are indicative of meteoric water. Connate water is the water in which the marine sediments or the original formation was deposited. It comprises the interstitial water of the reservoir rock and is characterized by chlorides, mainly sodium chloride, and high concentrations of dissolved solids. Mixed waters have both high chloride and sulfate-carbonate-bicarbonate concentrations suggesting meteoric water mixed or partially displaced by connate water (MMS, 1982).

The salinity and chemical composition vary from different strata and different petroleum reserves. The chlorides content of produced water ranges from 3,400 mg/l to 172,500 mg/l based on a study of 30 platforms in the Gulf of Mexico (U.S. EPA, 1985). Produced water generally contains little or no dissolved oxygen and the water may contain high concentrations of total organic carbon and dissolved organic carbon (Boesch and Rabalais, 1989).

Produced waters have also been found to include radioactive materials such as radium. Normal surface waters in the open ocean contain 0.05 pCi/liter of radium. Radionuclide data from Gulf coast drilling areas show Ra-226 concentrations of 16 to 393 pCi/liter and Ra-228 concentrations of 170 to 570 pCi/liter (U.S. EPA, 1978). After treatment using gas flotation, produced water radium concentrations are reduced by 10% (EPA, 1993).

Produced water production rates depend on the method of recovery used and the formation being drilled. Discharge rates can vary from none at some platforms to large quantities from central processing facilities. The EPA 30 platform study reports estimated discharge rates at 134 bbl/day to 150,000 bbl/day for offshore platforms in the central and western Gulf of Mexico (Burns and Roe, 1983). Currently, there are three platforms discharging produced water in the eastern Gulf. They are producing approximately 2 bbl/day, 160 bbl/day, and 240 bbls/day. Other facilities are presently piping to shore for treatment and discharge.

After treatment in an oil-water separator, produced water is usually discharged into the sea, or in some cases is reinjected for disposal or pressure maintenance purposes. Under the expiring permit,

Table 3-6. Produced Water Pollutant Concentrations[a]

Pollutant	Concentration (ug/l)
Oil and Grease	23.5 mg/l
TSS	30.0 mg/l
Priority and Non-Conventional Organic Pollutants:	
Anthracene	7.40
Benzene	1,225.91
Benzo(a)pyrene	4.65
2-Butanone	411.58
Chlorobenzene	7.79
Di-n-butylphthalate	6.43
2,4-Dimethylphenol	250.00
Ethylbenzene	62.18
n-Alkanes	656.60
Naphthalene	92.02
p-Chloro-m-cresol	10.10
Phenol	536.00
Steranes	31.00
Toluene	827.80
Triterpanes	31.20
Xylene (total)	378.01
Priority and Non-Conventional Metal Pollutants:	
Aluminum	49.93
Arsenic	73.08
Barium	35,560.83
Boron	16,473.76
Cadmium	14.47
Copper	284.58
Iron	3,146.15
Lead	124.86
Manganese	74.16
Nickel	1,091.49
Titanium	4.48
Zinc	133.85
Radionuclides:	
Radium-226	0.00020365
Radium-228	0.00024904

[a] Source: EPA, 1993.

produced water from the last stage of processing must meet a 48/72 mg/l oil and grease content limitation (monthly average/daily maximum). Under the proposed permit, this limitation is revised to be consistent with the final effluent guidelines as 29/42 mg/l (monthly average/daily maximum). The new limitation is based on the use of gas flotation for oil-water separation.

3.5 Produced Sand

Produced sand is the material removed from the produced water. Produced sand also includes desander discharge from the produced water waste stream and blowdown of water phase from the produced water treating system. Sands that are finer and of low volume may be drained into drums on deck or carried through the oil-water treatment system and appear as suspended solids in the produced water effluent, or they may be settled out in treatment vessels. If sand volumes are larger and sand particles coarser, the solids are removed in cyclone separators, thereby producing a solid-phase waste. The sand that drops out in these separators is generally contaminated with crude oil (oil production) or condensate (gas production) and requires washing to recover the oil. The sand is washed with water combined with detergents, or solvents. The oily water is directed to the produced water treatment system or to a separate oil-water separator to become part of the produced water discharge following oil separation. The final effluent guidelines, and therefore, the proposed permit prohibit the discharge of this waste stream.

3.6 Deck Drainage

Deck drainage is waste resulting from platform washings, deck washings, deck area spills, rainwater, and runoff from curbs, gutters, and drains, including drip pans and wash areas. The runoff collected as deck drainage also may include detergents used in deck and equipment washing.

In deck drainage, oil and detergents are the pollutants of primary concern. During drilling operations, spilled drilling fluids also can end up as deck drainage. Acids (hydrochloric, hydrofluoric, and various organic acids) used during workover operations may also contribute to deck drainage, but generally these are neutralized by deck wastes and/or brines prior to disposal.

A typical platform-supported rig is equipped with pans to collect deck and drilling floor drainage. The drainage is separated by gravity into waste material and liquid effluent. Waste materials are recovered in a sump tank, then treated and disposed, returned for use in the drilling mud system, or transported to shore. The liquid effluent, primarily washwater and rain water, is discharged.

EPA (1993) estimates the average discharge of deck drainage for platforms in the Gulf of Mexico as 50 bbl/day. The oil and grease levels reported for these deck drainage discharges are 28 mg/l monthly average and 75 mg/l daily maximum. Chevron estimates a discharge of 155 bbl/day during maximum drilling operations, 35 bbl/day during construction, and 300 bbl/day during full production.

3.7 Sanitary Waste

The sanitary wastes discharged offshore are human body wastes from toilets and urinals. The volume and concentrations of these wastes vary widely with time, occupancy, platform characteristics, and operational situation. Usually the toilets are flushed with brackish water or seawater. Due to the compact nature of the facilities, the wastes have less dilution water than common municipal wastes. This creates greater waste concentrations. Some platforms combine sanitary and domestic waste waters for treatment; others maintain sanitary wastes separate for chemical or physical treatment by an approved marine sanitation device.

3.8 Domestic Waste

Domestic wastes (gray water) originate from sinks, showers, safety showers, eye wash stations, laundries, food preparation areas, and galleys on the larger facilities. Domestic wastes also include solid materials such as paper, boxes, etc. These wastes are governed by the Coast Guard under MARPOL 73/78 (the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto). The Coast Guard regulations at 33 CFR Part 151 specify regulations for disposal of garbage. These are summarized in Table 3-7.

3.9 Cement

In order to protect the well from being penetrated by aquifers, it is necessary to install a casing in the bore hole. The casing is installed in stages of successively smaller diameters as the drilling progresses. The casings are cemented in place after each installation.

A cement slurry is mixed on site and is pumped through a special valve at the well head through the casing to the bottom and up the annular space between the bore hole wall and the outside of the casing to the surface. The cement is allowed to harden and drilling is resumed.

Most wells are cemented with an ordinary Portland cement slurry. The amount of cement used for each well depends on the well depth and the volume of the annular space. Additives are used to compensate for site-specific temperature and salt water conditions.

Table 3-7. Garbage Discharge Restrictions[a]

Garbage Type	Fixed or Floating Platforms & Associated Vessels[b] (33 CFR 151.73)
Plastics - includes synthetic ropes and fishing nets and plastic bags.	Disposal prohibited (33 CFR 151.67)
Dunnage, lining and packing materials that float.	Disposal prohibited
Paper, rags, glass, metal bottles, crockery and similar refuse.	Disposal prohibited
Paper, rags, glass, etc. comminuted or ground.[c]	Disposal prohibited
Victual waste not comminuted or ground.	Disposal prohibited
Victual waste comminuted or ground.[c]	Disposal prohibited less than 12 miles from nearest land and in navigable waters of the U.S.
Mixed garbage types.	See footnote d.

[a] Source: EPA, 1993.
[b] Fixed or floating platforms and associated vessels include all fixed or floating platforms engaged in exploration, exploitation, or associated offshore processing of seabed mineral resources, and all ships within 500 m of such platforms.
[c] Comminuted or ground garbage must be able to pass through a screen with a mesh size no larger than 25 mm (1 inch) (33 CFR 151.75).
[d] When garbage is mixed with other harmful substances having different disposal requirements, the more stringent disposal restrictions shall apply.

3.10 Well Treatment, Workover, and Completion Fluids

The following definitions are from the Development Document for the final effluent guidelines (EPA, 1993).

> Well treatment fluids are any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.
>
> Workover fluids are salt solutions, weighted brines, polymers and other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures.
>
> Completion fluids are salt solutions, weighted brines, polymers, and various additives used to prevent damage to the wellbore during operations which prepare the drilled well for hydrocarbon production.

The volume of fluids needed for workover, treatment, and completion operations depends on the type of well and the specific operation being performed. Chevron has based estimates average volumes of fluids (accounting for reuse of the fluids) as 300 bbl of workover fluids per job and 250 bbl of treatment fluids per treatment operation. Based on an assumption of one treatment or one workover every four years, an average of 200 bbl of treatment or workover fluid can be expected to be used per well every four years.

Well treatment fluids are acid in water solutions (using hydrochloric acid, hydrofluoric acid, and acetic acid). Formation solubility, reaction time, and reaction products determine the type of acid used. A treatment operation consists of a preparation solution of ammonium chloride (3-5 percent) to force the hydrocarbons into the formation; an acid solution; and a post-flush of ammonium chloride the remains in the formation for 12 to 24 hours to force the acid farther into the formation before being pumped out.

Solvents also may be used for well treatment, including hydrofluoric acid, hydrochloric acid, ethylene diaminetetraacetic acid (EDTA), ammonium chloride, nitrogen, methanol, xylene, and toluene. Additives such as corrosion inhibitors, mutual solvents, acid neutralizers, diverters, sequestering agents, and antisluding agents are often added to treatment fluid solutions. The pollutant concentrations for a well treatment fluid used in two wells at a THUMS facility in California are presented in Table 3-8.

Workover fluids are put into a well to allow safe repair and maintenance, for abandonment procedures, or to reopen plugged wells. During repair operations, the fluids are used to create hydrostatic pressure at the bottom of the well to control the flow of oil or gas and to carry materials out of the well bore. To reopen wells, fluids are used to stimulate the flow of hydrocarbons. Both of these operations must be accomplished without damaging the geologic strata.

To reopen or increase productivity in a well, hydraulic fracturing of the formation may be necessary. Hydraulic fracturing is achieved by pumping fluids into the bore hole at high pressure, frequently exceeding 10,000 psi. Proper fracturing accomplishes the following:

- Creates reservoir fractures thereby improving the flow of oil to the well
- Improves the ultimate oil recovery by extending the flow paths, and
- Aids in the enhanced oil recovery operation.

Over a period of time the fractures may close up. Materials can be introduced into the fissures to keep them open. Typical materials used include sand, ground walnut shells, aluminum spheres, glass beads, and other inert particles. These "propping agents" are carried into the fractures by the workover fluid.

High solids drilling fluids used during workover operations are not considered workover fluids by definition and therefore must meet drilling fluid effluent limitations before discharge may occur.

Table 3-8. Analysis of Fluids from an Acidizing Well Treatment[a]

Analyte	Concentration (ug/l)	Analyte	Concentration (ug/l)
Aluminum	53.1	Tin	6.66
Antimony	< 3.9	Titanium	0.68
Arsenic	< 1.9	Vanadium	36.1
Barium	12.6	Yttrium	0.19
Beryllium	< 0.1	Zinc	28.5
Boron	31.9	Aniline	434
Cadmium	0.4	Naphthalene	ND
Calcium	35.3	o-Toluidine	1,852
Chromium	19	2-Methylnaphthalene	ND
Cobalt	< 1.9		
		2,4,5-Trimethylanine	2,048
Copper	3.0	Oil and Grease	619
Iron	572	pH	2.48
Lead	< 9.82		
Magnesium	162		
Molybdenum	< 0.96		
Nickel	52.9		
Selenium	< 2.9		
Silver	< 0.7		
Sodium	1,640		
Thallium	5.0		

[a]Source: EPA, 1993.

Packer fluids, low solids fluids between the packer, production string, and well casing, are considered to be workover fluids and must meet only the effluent requirements imposed on workover fluids.

Well completion occurs if a commercial-level hydrocarbon reserve is discovered. Completion of a well involves setting and cementing the casing, perforating the casing and surrounding cement to provide a passage for oil and gas from the formation into the wellbore, installing production tubing, and packing the well. Completion fluids are used to plug the face of the producing formation while drilling or completion operation are conducted in hydrocarbon-bearing formations. They prevent fluids and solids from passing into the producing formation, thereby reducing its productivity or damaging the oil or gas.

The production zone is a porous rock formation containing the hydrocarbons, either oil or gas, and can be damaged by mud solids and water contained in drilling fluids. The completion fluids create a thin film of solids over the surface of the producing formation without forcing the solids into the formation. A successful completion fluid is one that does not cause permanent plugging of the formation pores. The composition of the completion fluid is site-specific depending on the nature of the producing formation. Drilling muds remaining in the wellbore during logging, casing, and cementing operations or during temporary abandonment of the well are not considered completion fluids and are regulated as drilling fluids discharges.

3.11 Blowout Preventer Fluids

A vegetable or mineral oil solution or antifreeze (polyaliphatic glycol) is used as a hydraulic fluid in BOP stacks while drilling a well. The blowout preventer may be located on the seafloor and is designed to contain pressures in the well that cannot be maintained by the drilling mud. Small quantities of BOP fluid are discharged periodically to the seafloor during testing of the blowout preventer device. The volume of BOP fluid discharge ranges from 67 to 314 bbl/day when testing (EPA, 1993).

3.12 Desalination Unit Discharge

This is the residual high-concentration brine discharged from distillation or reverse-osmosis units used for producing potable water and high-quality process water offshore. It has a chemical composition and ratio of major ions similar to seawater, but with high concentrations. This waste is discharged directly to the sea as a separate waste stream. The typical volume discharged from offshore facilities is less than 240 barrels per day.

3.13 Ballast Water and Storage Displacement Water

Ballast and storage displacement water are used to stabilize the structures while drilling from the surface of the water. Two types of ballast water are found in offshore producing areas (tanker and platform ballast). Tanker ballast water would not be covered under an NPDES permit.

Platform stabilization (ballast) water is taken on from the waters adjacent to the platform and may be contaminated with stored crude oil and oily platform slop water. More recently designed and constructed floating storage platforms use permanent ballast tanks that become contaminated with oil only in emergency situations when excess ballast must be taken on. Oily water can be treated through an oil-water separation process prior to discharge.

Storage displacement water from floating or semi-submersible offshore crude oil structures is mainly composed of seawater. Much of its volume can usually be discharged directly without treatment. Water that is contaminated with oil may be passed through an oil-water separator for treatment.

3.14 Bilge Water

Bilge water, which seeps into all floating vessels, is a minor waste for floating platforms. This seawater becomes contaminated with oil and grease and with solids such as rust where it collects at low points in vessels. This bilge water is usually directed to the oil-water separator system used for the treatment of ballast water or produced water, or it is discharged intermittently. The total volume of ballast/bilge water discharged is from 70 to 620 bbl/day (EPA, 1993).

3.15 Uncontaminated Seawater

Seawater used on the rig for various reasons is considered uncontaminated if chemicals are not added before it is discharged. Included in this discharge are waters used for fire control equipment and utility lift pump operation, pressure maintenance and secondary recovery projects, fire protection training, pressure testing, and non-contact cooling.

3.16 Boiler Blowdown

Boiler blowdown discharges consist of water discharged from boilers as is necessary to minimize solids build-up in the boilers, including vents from boilers and other heating systems.

3.17 Diatomaceous Earth Filter Media

Diatomaceous earth filter media are used in the filtration unit for seawater or other authorized completion fluids. They are periodically washed from the filtration unit for discharge.